NON-PUBLIC?: N
ACCESSION #: 9007240074
LICENSEE EVENT REPORT (LER)

FACILITY NAME: PLANT HATCH, UNIT 1 PAGE: 1 OF 8

DOCKET NUMBER: 05000321

TITLE: REACTOR SCRAM ON LOW REACTOR WATER LEVEL
EVENT DATE: 06/20/90 LER #: 90-013-00 REPORT DATE: 07/16/90

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 25

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
NAME: Steven B. Tipps, Manager Nuclear Safety and Compliance, Hatch

TELEPHONE: (912) 367-7851

COMPONENT FAILURE DESCRIPTION:
CAUSE: SYSTEM: COMPONENT: MANUFACTURER:
REPORTABLE NPRDS:

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On 6/20/90 at approximately 0245 CDT, Unit 1 was in the Run mode at an approximate power level of 600 CMWT (approximately 24.6% rated thermal power). At that time, the reactor scrammed on low reactor vessel water level. Water level decreased to the scram setpoint when the 1B Reactor Feedwater Pump (RFP) failed to respond to an increasing demand signal from the Master Feedwater Control Unit or the 1B RFP Control Unit (the 1A RFP had been removed from service earlier). Group 2 and 5 Primary Containment Isolation System (PCIS) signals were received and all Group 2 and the inboard Group 5 Primary Containment Isolation Valves (PCIVs) closed. The High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems automatically initiated and injected per design. Unit 1 and Unit 2 Standby Gas Treatment (SBGT) systems received automatic initiation signals and the 1A train started (the 2A train was already running at the time of the event.)

The cause of this event is unknown. The 1B RFP responded as if high pressure steam to the 1B RFP turbine was unavailable. However, no evidence high pressure steam was not available could be found in the investigation following the event.

Corrective actions for this event included testing of the master and 1B RFP control loops, visual inspection and testing of the 1B RFP turbine controls, and testing of the 1B RFP during unit startup.

END OF ABSTRACT

PLANT AND SYSTEM IDENTIFICATION

General Electric - Boiling Water Reactor Energy Industry Identification System codes are identified in the text as (EIIS Code XX).

SUMMARY OF EVENT

On 6/20/90 at approximately 0245 CDT, Unit 1 was in the Run mode at an approximate power level of 600 CMWT (approximately 24.6% rated thermal power). At that time, the reactor scrammed on low reactor vessel water level. Water level decreased to the scram setpoint when the 1B Reactor Feedwater Pump (RFP, EIIS Code SJ) failed to respond to an increasing demand signal from the Master Feedwater Control Unit or the 1B RFP Control Unit (the 1A RFP had been removed from service earlier). Group 2 and 5 Primary Containment Isolation System (PCIS, EIIS Code JM) signals were received and all Group 2 and the inboard Group 5 Primary Containment Isolation Valves (PCIVs) closed. The High Pressure Coolant Injection (HPCI, EIIS Code BG) and Reactor Core Isolation Cooling (RCIC, EIIS Code BN) systems automatically initiated and injected per design. Unit 1 and Unit 2 Standby Gas Treatment (SBGT, EIIS Code BH) systems received automatic initiation signals and the 1A train started (the 2A train was already running at the time of the event.)

The cause of this event is unknown. The 1B RFP responded as if high pressure steam to the 1B RFP turbine was unavailable. However, no evidence high pressure steam was not available could be found in the investigation following the event.

Corrective actions for this event included testing of the master and 1B RFP control loops, visual inspection and testing of the 1B RFP turbine controls, and testing of the 1B RFP during unit startup.

DESCRIPTION OF EVENT

On 6/19/90 at approximately 2015 CDT, Unit 1 was in the Run mode at an approximate power level of 1932 CMWT (approximately 79% rated thermal power). At that time, the unit was decreasing power per Management direction in response to a high water level in the Condenser's "A" Hotwell (EIIS Code SQ). Power was being reduced stepwise to see if the water level in the hotwell would decrease.

At approximately 2315 CDT, the 1A RFP was removed from service as reactor power was at the point where one RFP could maintain reactor vessel water level. The 1A RFP was left running at about 2000 rpm; at this speed, the pump can not generate enough discharge pressure to inject feedwater into the reactor vessel. Therefore, the 1A RFP was discharging through its minimum flow line. The 1B RFP was maintaining reactor vessel water level.

On 6/20/90 at approximately 0217 CDT, the 1A RFP was tripped and its suction valve closed. At approximately 0240 CDT, the "C" Condensate Booster Pump (EIIS Code SD) was removed from service per procedure 34GO-OPS-013-1S, "Normal Plant Shutdown." At that point, reactor power (approximately 26% rated thermal power) was low enough for one Condensate Booster Pump and one RFP to maintain reactor vessel water level. When the "C" pump was removed from service, the "B" Condensate Booster Pump was the only booster pump in service.

When the "C" Condensate Booster Pump was removed from service, feedwater flow rapidly decreased and then increased as the 1B RFP's suction pressure momentarily decreased. This is an expected response when a booster pump is removed from service; however, feedwater flow did not fully recover to its previous level. Consequently, reactor vessel water level began a slow, steady decrease approximately 30 seconds after the booster pump was removed from service.

The Master Feedwater Control Unit initially responded to the decrease in reactor vessel water level by decreasing demand to the 1B RFP; this was an unexpected and incorrect response. At a water level of approximately 30 i
ches above instrument zero (approximately 194 inches above the top of active fuel), the master controller's demand signal reversed and began to demand an increase in feedwater flow. However, water level continued to decrease so, at about 25 inches above instrument zero, licensed Operations personnel took control of the 1B RFP using its individual controller. An operator increased the controller's demand signal to

100%, but, after an initial pump response when it increased speed from 2800 rpm to its original value of about 3200 rpm, the pump did not respond to its controller. Reactor vessel water level continued to decrease.

In the few seconds preceding the scram, licensed Operations supervisory personnel prepared to take manual control of the 1B RFP turbine controls. To do this, the Motor Speed Changer (MSC) was taken off of its high speed stop (set at approximately 6100 rpm and well above normal pump speed). When the MSC was taken off of its high speed stop, pump speed unexpectedly decreased from 3200 rpm to 3000 rpm. This should not have happened because, at the indicated pump speed, the Motor Gear Unit (MGU) should have been controlling pump speed via the control units. Due to this unexpected response, the MSC was run back to its high speed stop. Pump speed returned to 3200 rpm.

Reactor water level decreased to the scram setpoint of approximately 12.3 inches above instrument zero and, at approximately 0245 CDT, the unit scrammed. At that water level, a Group 2 PCIS signal was received and the Group 2 PCIVs closed per design. Reactor vessel water level decreased to approximately 35 inches below instrument zero (129 inches above the top of active fuel) due to void collapse. The HPCI and RCIC systems automatically initiated and injected into the vessel per design. At 0250 CDT, the 1A RFP was placed into service to control water level; HPCI and RCIC were secured at 0248 CDT and 0250 CDT, respectively.

Also at 35 inches below instrument zero, Group 5 PCIS and Unit 1 and Unit 2 SBGT system automatic initiation signals were received. The inboard Group 5 PCIV closed and the 1A SBGT train started (the 2A train was already running at the time of the event). The outboard Group 5 PCIV did not close and the 1B and 2B SBGT trains did not start. Investigation revealed this was an appropriate response given the interaction between the minimum reactor water level reached in the event and the allowed uncertainty of the reactor water level setpoint. The "C" reactor vessel water level channel for the Group 5 PCIS and SBGT system automatic initiation logic did not trip. Therefore, the minimum logic necessary to isolate the outboard Group 5 PCIV and start the 1B and 2B SBGT trains, i. e., the "C" and "D" channels, did not actuate. Each trip unit's setpoint is established based on a setpoint methodology which provides a margin between the actual setpoint and the limit in the Technical Specifications. This margin consists of allowances for expected transmitter and trip unit drift and also provides a 'leave alone band' referred to as the instrument's tolerance (an instrument found within this band during calibration does not need to have the setpoint adjusted).

A loop calibration check of the "C" channel found the transmitter's output was slightly out of tolerance at two of the five calibration points over the transmitter's range. Thus, the transmitter was sensing a water level slightly (less than one inch) higher than actual. However, the instrument's drift was well within that allowed for in the establishment of the setpoint. Therefore, the "C" logic channel would have actuated well before water level would have reached the Technical Specifications required trip setpoint of 47 inches below instrument zero (in this event the water level reached 35 inches below instrument zero, the nominal trip setpoint and quickly recovered).

Reactor vessel pressure was controlled initially with HPCI and RCIC and later with the 1A RFP turbine. No bypass valves or safety relief valves actuated during this event.

CAUSE OF THE EVENT

The cause of this event is unknown. The 1B RPP responded as if high pressure steam to the 1B RFP turbine was unavailable. This would have left only the low pressure steam supply to turn the pump's turbine. At low power, the low pressure steam would not have contained enough energy to increase pump speed to compensate for the tripping of the "C" Condensate Booster Pump. As a result, feedwater flow would have decreased and the pump would not have responded to the increasing demand signal from its controllers.

There are two sources of steam to the RFP's turbines: a low pressure supply and a high pressure supply. Each supply has a control valve which opens to admit steam to the turbine. The valves' positions are determined by the MSC and MGU.

Upon initial startup, turbine speed is controlled with the MSC. When turbine speed reaches approximately 2000 rpm, the MGU is used to control turbine speed and the MSC is run manually to its high speed stop. The control system is designed such that the device demanding the lowest speed is the controlling device; therefore, the MSC is placed at the high speed stop to ensure it is always demanding the highest speed and will not be the controlling device. The MGU is then used, via the Master Control Unit, to control turbine/pump speed to maintain water level at a prescribed point.

At the power level preceding the scram, low pressure steam supply pressure was approximately 40 psig (at 100% power, it is about 135 psig). This was sufficient to maintain pump speed at that necessary to maintain water level within its normal band when two Condensate Booster Pumps were in service. High pressure steam was not needed, thus, the high pressure control valve was closed.

When the booster pump was removed from service, the decreased RFP suction pressure caused feedwater flow to drop. The pump's speed had to increase to restore feedwater flow to its original value. Due to a momentary problem with the Master Control Unit, pump speed decreased from 3200 rpm to 2800 rpm. (It should be noted the controller's initial incorrect response was not a significant contributing factor in this event. Water level would have continued to decrease regardless of the demand signal since pump speed would not increase above 3200 rpm). As water level continued to decrease, this problem disappeared and the control unit began to demand an increased pump speed. Pump speed began to increase as the MGU caused the low pressure control valve to open.

At this time, an Operator took manual control of the pump using the pump's individual controller. He ran its demand to 100% and the pump's speed returned to 3200 rpm. As the demand was still 100%, the MGU continued to its high speed stop (about 6050 rpm). This would have caused the low pressure steam control valve to open and then the high pressure control valve to open. However, pump speed did not increase above 3200 rpm (per General Electric personnel this is about the maximum speed at which steam at 40 psig can turn the RFP turbine). It appears the MGU responded properly to the control units because the MSC became the controlling device when it was taken off its high speed stop and its speed signal became the lower of the two devices. That the MSC was the controlling device is evidenced by the fact pump speed decreased and then increased when it was lowered and raised, respectively. Thus, it is concluded the control loop responded properly (except for its initial response) and the problem may have been no high pressure steam available to the RFP turbine.

To determine if the cause of the event was indeed the lack of high pressure steam available to the 1B RFP turbine, as was potentially indicated by the turbine response during the event as described above, extensive testing of the turbine and its control system was conducted which is described in more detail in the following corrective action section of this report. This testing revealed no evidence that high pressure steam was unavailable to the turbine; no problems were found in the feedwater control loop, the turbine control system, or the turbine steam supply.

REPORTABILITY ANALYSIS AND SAFETY ASSESSMENT

This report is required per 10 CFR 50.73(a)(2)(iv) because an unplanned actuation of the Reactor Protection System (RPS, EIIS Code JC) and Engineered Safety Features (ESFs) occurred. Specifically, the RPS was initiated automatically on low reactor water level. The ESFs which activated during this event were the Primary Containment Isolation System valve Group 2 and Group 5 (partial), the High Pressure Coolant Injection system and the "A" trains of the Unit 1 and Unit 2 Standby Gas Treatment systems.

The RPS provides timely protection against the onset and consequences of conditions that could threat the integrity of the fuel barriers and the nuclear system process barrier. A reactor scram initiated by a low water level condition protects the fuel by reducing the fission heat generation within the core. In this event, the decrease in vessel level was a direct result of the failure of the 1B RFP to respond to signals from the feedwater system controllers. The RPS functioned per design. Reactor water level was restored quickly by using the 1A RFP, the High Pressure Coolant Injection system, and the Reactor Core Isolation Cooling system. At no time was water level less than 129 inches above the top of the active fuel. All systems functioned as designed to restore water level to its normal level. Based on this information, it is concluded that this event had no adverse impact on nuclear safety. Additionally, the above analysis is applicable to all power levels.

CORRECTIVE ACTIONS

Extensive checks, dynamic testing, and visual inspection of the 1B RFP turbine and its control system were performed. The Master Feedwater Controller loop from the water level sensor to the MGU's output was checked for response to varying water level input signals. The Master Controller responded by increasing the demand signal to the MGU on a decreasing water level signal and decreasing the demand signal on an increasing water level signal. The output signal from the MGU followed the demand signal from the controllers. The control loop functioned per design.

The response of the turbine control system to signals from the 1B RFP individual controller also was checked. The demand signal was increased and decreased manually at the controller and the turbine's control valves were confirmed visually to open and close, respectively. The control system functioned per design. Accessible portions of the overall 1B RFP control system were visually inspected as well. No problems were found.

During unit startup, the 1B RFP turbine's response with steam being supplied was checked. It was verified the high pressure stop valve was open and the high pressure control valve opened as designed to admit steam to the RFP turbine. The turbine responded as expected thereby confirming the high pressure steam supply was not isolated. Turbine response on low pressure steam also was checked. This check was one with low pressure steam at approximately the pressure at the time of the scram. The turbine responded to signals from its controller per design.

The above described testing revealed no problems in the feedwater control loop, the turbine control system, or the turbine steam supply. However, prior to unit startup, a Data Acquisition and Analysis System (DAAS) was connected to the Feedwater Control System. The DAAS will monitor an

record various system parameters such as controller input and output. This will allow for identification of control system problems if they recur. The 1B RFP was placed into service and unit power was increased to 100% rated thermal power with no problems.

ADDITIONAL INFORMATION

1. Other Systems Affected:

No systems other than RPS, PCIS, SBGT, HPCI, and RCIC were affected by this event.

2. Failed Component Information:

There were no failed components associated with this event.

3. Previous Similar Events:

There were five previous similar events recently in which loss of feedwater resulted in low reactor vessel water level and a reactor scram. These events were reported in LER 50-321/1988-013 dated 10/3/88, LER 50-366/1989-005 dated 9/27/89, LER 50-366/1988-008 dated 4/20/88, LER 50-366/1988-017 dated 6/27/88, and LER 50-366/1988-020 dated 9/6/88. The corrective actions for these five events would not have prevented this event because the causes were different. This event appears to have been caused by a problem in the RFP turbine's steam supply whereas three of the previous events resulted from component failures in the control circuit and two resulted from deficient procedures.

ATTACHMENT 1 TO 9007240074 PAGE 1 OF 2

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July 16, 1990

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PLANT HATCH - UNIT 1
NRC DOCKET 50-321
OPERATING LICENSE DPR-57
LICENSEE EVENT REPORT
REACTOR SCRAM ON LOW REACTOR WATER LEVEL

Gentlemen:
In accordance with the requirements of 10 CFR 50.73(a) (2) (iv), Georgia Power Company is submitting the enclosed Licensee Event Report (LER) concerning the unanticipated actuation of some Engineered Safety Features (ESFs). This event occurred at Plant Hatch - Unit 1.

Sincerely,

W. G. Hairston, III

JJP/ct

Enclosure: LER 50-321/1990-013

c: (See next page.)

GeorgiaPower

U.S. Nuclear Regulatory Commission
July 16, 1990
Page Two

c: Georgia Power Company
Mr. H. C. Nix, General Manager - Nuclear Plant
Mr. J. D. Heidt, Manager Engineering and Licensing - Hatch
GO-NORMS

U.S. NUCLEAR Regulatory Commission, Washington, D.C.
Mr. L. P. Crocker, Licensing Project Manager - Hatch

U.S. Nuclear Regulatory Commission, Region II
Mr. S. D. Ebneter, Regional Administrator
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